CALIFORNIA ENERGY COMMISSION
1516 Ninth Street, MS-29
Sacramento, California 95814

Web Site: www.energy.ca.gov

December 20, 2000

TO ALL INTERESTED PARTIES:

This draft report contains a portion of the Energy Commission s tasks under AB 970 (Wright) passed in the 2000 legislative session. It contains the short-term trends analysis that were requested by the Legislature and focuses on market structure and rules, as well as actions by major participants in the deregulated electricity market.

The recommendations and observations are intended to be the subject of a workshop sponsored by the Electricity and Natural Gas Committee on January 4, 2001. Because of the tight time constraints contained in the legislation, a full formal review of this document by the Electricity and Natural Gas Committee was not possible at this time.

As a consequence, this document is being released by this office and does not reflect concurrence by either the full Committee or of the full Commission. Results from the workshop will be used by the Electricity and Natural Gas committee to prepare a report for the full Commission.

Sincerely,

MICHAL C. MOORE
Commissioner and Presiding Member
Electricity and Natural Gas Committee

STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of :	)	Docket 99-CEO-I
	)	
Draft AB 970 Trends Report	)	NOTICE OF WORKSHOP
	)	

Commissioner Michal Moore is releasing the ***Draft AB 970 Trends Report: Executive Summary & Recommendations***. This report was prepared in response to AB 970, which requires the Energy Commission to prepare a report that includes the following: an assessment of energy consumption trends; the status of electricity supply, demand, and conservation, along with recommendations to ensure adequate supply and energy conservation in the State. The draft report outlines a number of potential temporary mitigation measures for the summer of 2001 that if implemented would help to prevent a continuation of electricity market problems and lead to more effective market reforms in the future. Following this workshop, the Electricity & Natural Gas Committee will prepare a Committee Report for the Commission.

The Energy Commission is also in the process of developing its *California Energy Outlook* that addresses short-term and long-term trends in electricity and natural gas markets, as well as for transportation. The Energy Commission hopes to release the *California Energy Outlook,* which will serve to supplement the *Draft AB 970 Trends Report*.

The Committee will hold a workshop to take parties comments on the attached draft report on:

THURSDAY, JANUARY 4, 2001
Beginning at 10 a.m.
CALIFORNIA ENERGY COMMISSION
1516 Ninth Street
Hearing Room A
Sacramento, California
(Wheelchair Accessible)

Parties will have the opportunity to file written comments up to the time of the workshop. Those submitting written comments should provide 12 copies to the Commission s Docket Unit. Those interested in filing comments by e-mail may send them to <docket@energy.state.ca.us> and need submit only one hard copy to the Docket Unit.

Comments can also be mailed to:

CALIFORNIA ENERGY COMMISSION
Dockets Office
Attn: Docket 99-CEO-I
1516 9th St., MS-4
Sacramento CA 95814-5512

Any person with questions regarding this notice should contact Al Alvarado, Project Manager, at (916) 654-4749 or e-mail at <aalvarad@energy.state.ca.us>. You may also contact Melissa Jones, Policy Advisor to Commissioner Michal C. Moore, at (916) 654-3787 or e-mail at <mjones@energy.state.ca.us>. If you wish assistance in participating in the workshop, call Roberta Mendonca, Public Adviser, at (916) 654-4489, toll-free in California at (800) 822-6228 or e-mail the public adviser at <pao@energy.state.ca.us>. If you require special accommodation at the workshop, please all Robert Sifuentes at (916) 654-5004 at least five days before the workshop. News media inquiries should be directed to Assistant Director Claudia Chandler at (916) 654-4989.

Date: ______________________

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MICHAL C. MOORE
Commissioner and Presiding Member
Electricity & Natural Gas Committee

CALIFORNIA
ENERGY
COMMISSION

AB 970 TRENDS REPORT EXECUTIVE SUMMARY & RECOMMENDATIONS

DRAFT REPORT

COMMISSIONER MICHAL C. MOORE

PRESIDING MEMBER
ELECTRICITY & NATURAL GAS COMMITTEE

DECEMBER 2000
P300-00-007

Gray Davis, *Governor*

DRAFT

AB 970 Trends Report
EXECUTIVE SUMMARY
AND
RECOMMENDATIONS

Electricity & Natural Gas Committee

December 20, 2000

Disclaimer

This report was prepared by the California Energy Commission s Electricity and Natural Gas Committee to meet reporting requirements established under AB 970. This report is scheduled for a Committee Workshop on January 4, 2001. It will be scheduled for possible adoption at a future Commission business meeting. The views and recommendations contained in this document are not the official policy of the Energy Commission until a final report is formally adopted.

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EXECUTIVE SUMMARY

INTRODUCTION

The Presiding Member of the California Energy Commission s (Energy Commission) Electricity and Natural Gas Committee has prepared this report in response to Assembly Bill 970 (AB 970).

The Committee believes that the most immediate issue facing energy policy makers today is how to mitigate two problems: high electricity prices and threats to electric system reliability. Concerns about these two problems were heightened during the summer of 2001 and continue today. Although the report focuses on short-term measures, the proposed recommendations should also help to stabilize the market for the period beyond 2001.

The Committee s report proposes a number of mitigation measures. The Committee recognizes that implementing measures to alleviate the negative impacts of current market structure and outcomes will require the combined efforts of a number of federal, state, regional and local agencies.

In addition, the Committee believes that it is essential to gain the views and experience of the interested parties who either have a role in the electricity market or who can contribute to the understanding of how markets behave. This input is necessary to assure that final recommendations, developed as a result of workshops and hearings on the *Draft AB 970 Trends Report*, achieve their intended results and do not cause unanticipated negative consequences.

With this goal in mind, the Committee has scheduled a workshop for January 4, 2001 to discuss these and other approaches to address the current problems being experienced in the electricity market.

PURPOSE OF THE REPORT

The events during the summer of 2000 prompted numerous investigations into the causes and possible solutions to California s electricity problems at the state and federal level.

In September 2000, the California Legislature enacted AB 970 that requires the Energy Commission to prepare a report for the Governor and Legislature that includes: an assessment of energy consumption trends; status of electricity supply, demand and conservation; and recommendations to ensure adequate supply and energy conservation in the State.

AB 970 specifically refers to the Energy Commission s duties to assess trends outlined in Public Resource Code Section 25216. Under this section, the Energy Commission must undertake a continuing assessment of trends in the consumption of electric energy and other forms of energy and analyze the social, economic and environmental consequences of these trends . It further directs the Energy Commission to independently analyze forecasts in relation to statewide estimates of population, economic and other growth factors and in terms of the availability of energy resources, costs to consumers and other factors .

Restructuring changed the fundamental mechanisms for balancing electricity supply and demand by moving from regulatory command and control to reliance on competitive markets. As a result, trends in the restructured electricity market have become a more important element of the Energy Commission assessment responsibilities.

The trends in this restructured market over the last several months, however, have raised serious questions about the ability of the current market structure and specific rules that motivate participants to provide affordable and reliable electricity supplies for California s residents and businesses.

Consequently, this report addresses some of the more troubling trends that have developed in the electricity market since the beginning of the summer of 2000. The consequences of current electricity market problems include the following:

§ Extremely high electricity costs,
§ Decreased reliability,
§ Increased emission of pollutants,
§ Very high profits by generators and wholesale power sellers,
§ Large debt incurred by utility distribution companies, and
§ Large amounts of California revenues flowing out of state.

Many of these consequences are due to flaws in market design and rules that FERC is currently addressing.[1] While redesign of the California market will be necessary to correct the major flaws, it is extremely important that this be done in a deliberate and thoughtful manner. Many of the proposed solutions to market flaws being addressed at FERC may only serve to create other flaws and perverse incentives that could exacerbate excessively high prices and reliability concerns. Given the short time left, the Committee believes that it is highly unlikely that effective and efficient redesign of the market can be agreed to and implemented before the summer of 2001.

To address this concern, this report outlines a number of potential mitigation measures for the near term for discussion and comment in its January 4, 2001

[1] A number of market flaws are identified in *FERC Order Proposing Remedies for California Wholesale Electricity Markets* and *Staff Report to FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000. See also the ISO s Market Surveillance Committee Reports dated October 18, 1999, March 9, 2000, July 6, 2000, September 6, 2000 and December 1, 2000.

workshop. These potential mitigation measures could help to prevent a continuation of current market problems and lead to more effective market reforms in the future.

The Committee is also in the process of developing its *California Energy Outlook* that addresses short-term and long-term trends in electricity and natural gas markets, as well as transportation fuels. The *California Energy Outlook* will provide the full assessment required of the status of electricity supply, demand and conservation required under AB 970. The Committee hopes to release the *Draft California Energy Outlook*, which will serve to supplement this report, by the end of January 2001.

HEIGHTENED CONCERNS OVER ELECTRICITY PRICE AND RELIABILITY PROBLEMS

California s electricity market is in tremendous turmoil as policy makers and regulators attempt to understand what has gone wrong in the restructured market and struggle to develop solutions. During the summer of 2000, the State experienced spiraling wholesale electricity costs, exacerbated by a doubling in natural gas prices for electric generation.

In the months of June through August 2000, the costs for energy in wholesale electricity markets run by the California Independent System Operator (ISO) and California Power Exchange (PX) totaled over $10 billion, compared with a total cost of a little over $2 billion for the same period in 1999. This five-fold increase in electricity costs, which nearly tripled the electricity bills of San Diego customers in June 2000, caused a consumer backlash. During the months of September through November 2000, payments for energy in the wholesale ISO and PX markets continued at very high levels totaling over $7 billion, compared to about $2 billion for the same period in 1999.

These extremely high prices in the summer were partly a result of constrained supply conditions during the peak summer demand for electricity in the State. The more disturbing trend is that prices continued to climb in the fall and winter of 2000, the off-peak period for electricity consumption in California.

In addition to high prices, the reliability of the grid in California was in serious jeopardy numerous times throughout the summer and, more surprisingly, during the fall of 2000. As recently as December 13, 2000, the ISO came close to implementing rolling blackouts because supplies were insufficient to meet demand. California narrowly avoided blackouts because of the assistance of Secretary of Energy s timely actions to make generating capacity available to the ISO.[2]

[2] A DOE press release reported that on December 13, 2000 U.S. Energy Secretary Bill Richardson said he invoked the government s rarely-used authority under the Federal Power Act to require out-of-state generators and marketers currently balking at selling power into California to do so immediately.

California cannot afford to incur the level of wholesale (and ultimately retail) electricity costs experienced over the last several months for a commodity so important to the health, safety and welfare of its citizens and economy. Nor can California afford to pay sustained prices at these levels into the future without incurring serious cost impacts for its citizens and businesses, as well as the economy as a whole. Worst of all, despite high prices declining reliability due to market problems poses unacceptable costs and risks.

Public representatives have testified about the concerns posed by problems in the electricity market at hearings in San Diego that occurred this past summer. Representatives statements include the following:

> Governor Davis stated that The summer of 2000 has confronted California with an electricity crisis that seriously threatens the safety, health and well-being of citizens and businesses throughout the State.
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> Diane Jacob, chair of the San Diego County Board of Supervisors testified that San Diego is on the brink of a human and economic disaster ; and, The increase has placed an incredible burden on both our businesses and San Diego residents. In particular, many of those who are senior citizens, the elderly, who are on fixed incomes. Several local residents, such as the 100,000 mostly senior citizens in mobile home parks, they have no choice but to pay their electricity bills or they face eviction. Many are having to decide between buying food, buying essentials, such as their medicines, which are life-sustaining, or life-saving medical devices or paying their electricity. And that is not a choice that anyone should be faced with.
>
> State Senator Debra Bowen stated, kids are trying to learn in a classroom that s 120 degrees.
>
> Congressman Robert Filner declared, hear what real people say about their real problems. And the rage and the frustration, the fear, the panic in people s voices.
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> State Senator Dede Alpert reported, I have heard accounts of businesses laying off people and shutting their doors, of elderly people who can t afford to run air-conditioning, and middle class families who cannot pay their utility bill.
>
> United States Senator Barbara Boxer added, All of our people that live on a budget are suffering. Many small businesses are threatened with bankruptcy. Nearby farmers can no longer irrigate their crops with electrical powered pumps. And senior citizens living on fixed incomes are forced to consider turning off their air conditioners during the summer s hottest months. It is no exaggeration to say this energy crisis threatens San Diego s economic viability and, in some cases, the physical health of its residents.

TRENDS IN CALIFORNIA S ELECTRICITY MARKET

Electricity supply scarcity has contributed to high wholesale electricity costs and reliability problems in California. Over the past decade, surplus electricity supplies have become increasingly scarce throughout the Western Region as demand growth has outstripped power plant construction. To add to last summer s resource outlook, the Pacific Northwest had slightly lower than normal hydro conditions. This resulted in extremely tight electricity supplies for California, which has historically relied on substantial imports to supplement in-state generation. Hydroelectric facilities were operated so extensively this year that if heavy rains and snows do not refill drawn-down reservoirs this winter, California s ability to meet peak demand in 2001 will be diminished.

High Electricity Prices

California s electricity market experienced severe and volatile price fluctuations during the summer and fall of 2000. In the June through September period, California spent over $10 billion on electricity in the wholesale electricity markets run by the ISO and PX, more than was spent in the entire one-year period of 1999.[3] From January through September of 2000, total electricity costs exceeded $16˚billion, more than triple the amount spent during the same period in 1999.

In the ISO and PX markets, the monthly average cost of electricity per megawatt-hour (MWh) peaked at about $50 in October 1999, while the peak cost per kWh that occurred in August of 2000 was about $168 per MWh. Prices continued to climb to an average of $392 per MWh for the first two weeks of December, with actual prices as high as $1,142 per MWh on December 13, 2000.

Over the summer of 2000, natural gas prices doubled compared to the previous summer from $2.50 per million British thermal units (MMBtu) to well over $5.00 per MMBtu. Natural gas prices have continued to increase throughout the fall of 2000. In early December 2000, average prices for natural gas for electric generators had reached levels of about $34 per MMBtu in Northern California and $37 per MMBtu in Southern California. Since many of the existing power plants in California are fueled by natural gas, increased natural gas prices have substantially increased the operating costs of these plants.

In addition, the cost of air emission credits necessary to operate existing California power plants went from $2˚per pound of nitrogen oxides (NO_x) to nearly $50 per pound of NO_x. Another contributor to high electricity costs and reliability problems starting in the summer of 2000 and continuing today is a sizeable increase in the incidence of unplanned power plant outages in the United State.

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[3] California Independent System Operator, Summary of Energy and AS Costs, October 2000. California paid about $7 billion for ISO/PX electricity products in 1999.

At the same time, owners of generators sold off by utilities have earned huge profits, allowing them to nearly pay off their investments in California power plants in a single summer season. Los Angeles Department of Water & Power (LADWP), which is not a member of the ISO, had surplus capacity that was sold into the California market for well over $100 million this past summer. Spiraling wholesale electricity prices nearly tripled the July bills of residential and small commercial customers in the San Diego area. In response to consumer alarm at facing electricity bills they simply could not afford to pay, the Legislature placed a cap on the rates San Diego Gas & Electric Company (SDG&E) could charge its customers.[4]

While generators, including utility affiliates, were making enormous profits off system conditions this summer, the regulated utility distribution companies were forced to purchase extremely high-cost electricity to meet the needs of their customers. Because these utilities are subject to the rate-freeze provisions of AB 1890, the extra costs for buying electricity could not be passed on to their customers. Although this protects the utilities customers from increased wholesale electricity costs, there is still uncertainty over who will pay these costs and when.[5] Even municipal utilities that are not members of the ISO, such as Sacramento Municipal Utility District (SMUD), were forced to use financial reserves to cover purchases during the summer.

Declining Reliability

The second major problem in California electricity market is declining reliability of the electricity system. The ISO declared system emergencies on 88 separate occasions so far in 2000, compared with five in 1999 and 12 in 1998. To maintain the integrity of the electricity grid the ISO called on interruptible customers to reduce demand 17 times during the summer of 2000, compared with 5 times in 1998 and once in 1999.

Reliability problems continued into the fall of 2000. In November and December many Stage 2 alerts were called and customers were interrupted on several occasions as very large amounts of generation in the State experienced outages. More alerts have been called in December 2000 alone than in all of 1998 and 1999 combined. On December 13, 2000 the ISO narrowly avoided having to institute rolling blackouts to residential and small commercial customers.

[4] AB 265 created a frozen energy commodity rate for SDG&E residential and small commercial customers at the level of $0.065 per kWh through the end of 2002. In addition, larger customers (up to 100 KW) are permitted to opt into a frozen rate of $0.065, however they must pay any differenced between this rate and actual market rates after twelve months.

[5] SCE and PG&E have filed rate stabilization plans with the CPUC seeking to both recover uncollected energy revenues due to past high PX and ISO prices as well as addressing expected future high energy prices. Both proposed plans increase current rates for multiple years. Both plans appear to rely upon wholesale electricity prices being lower in the future so that near-term undercollections from end-users are balanced by overcollections in future years.

Causes of Market Problems

During the debate about the cause of California electricity problems, some have argued that price volatility is an inevitable characteristic of markets run by the ISO and PX; i.e. that high prices experienced in electricity market in 2000 are not a totally unexpected phenomenon. It is true that periods of price spikes and supply shortages are common in commodity markets, particularly in markets like electricity that require significant capital investments. On the other hand, price collapses and supply excesses have historically been common in such markets as well.

Commodity markets use high prices to induce investments in new production capacity. Generally speaking, rising prices from shortages of capacity encourage the construction of new power plants and/or expansion of existing facilities. In most markets, as these additional resources come on-line, prices tend to decline. As a consequence, idle capacity may lead to temporary plant shutdowns, and investors planning to construct new facilities may defer those plans to await higher prices.

However, the electricity market may be inherently different from other commodity markets due to the physical reality that coordination of the system is absolutely critical.[6] In addition, the high variability of demand for electricity that is primarily weather-driven can exacerbate the cyclic nature described above. Another distinguishing characteristic of electricity markets is extremely limited storage, or stockpiling, opportunities that help other markets to control exposure to wide price swings.

Notwithstanding the nature of commodity markets, many entities — including the California Public Utilities Commission (CPUC), the Electricity Oversight Board (EOB), the Federal Energy Regulatory Commission (FERC) and the ISO s Market Surveillance Committee (MSC) — have concluded that flaws in market design and rules are a major factor in the excessively high prices for electricity. Weather conditions, tight supplies, increased costs of natural gas and high emission credit costs also contributed to higher costs for electricity this summer. However, these factors do not adequately explain the levels of prices seen in the ISO and PX markets from the summer of 2000 to present.

Problems in the market structure and rules are also a major contributor to high prices during the summer of 2000. Some of the major flaws that have been identified include:

§ Exercise of market power to raise wholesale electricity costs,

§ Lack of demand responsiveness,

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[6] *Electricity Market Reform in California*, John D. Chandley, Scott M. Harvey, and William W. Hogan, November 22, 2000 provides the following description of the need for system coordination: Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. These same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances.

- Artificial separation of the ISO and PX markets,
- Out of market purchases above price caps,
- Limited ability of UDCs to use forward contracts,
- Conflicts of interest for ISO Stakeholder Board,
- Unintended consequences of RECLAIM on the electricity market, and
- Increased emissions due to market inefficiencies.

SUMMARY OF RECOMMENDATIONS

The Committee supports the efforts of the Governor and the Legislature to obtain refunds for wholesale customers who, according to FERC, paid unjust and unreasonable prices for electricity since last summer.[7] A continuation of the unaffordable prices will seriously dampen some electricity usage, potentially crippling the economy and devastating the health and welfare of the citizens of California.

The Committee is proposing mitigation measures, listed below and addressed in greater detail in the remainder of the report. Many of these recommendations may be drastic and, therefore, should be implemented for the short term only.[8] The Committee believes that, above all else, California cannot afford a continuation of events in the electricity market that started in the summer of 2000 and persist today. California s citizens and businesses critically need an affordable and reliable electricity market. It is toward that end that the Committee proposes the following potential mitigation recommendations for discussion and comment.

Proposed Market Mitigation Recommendations

1. Implement Changes in ISO Board & PX Buy/Sell Requirements

The Legislature should immediately create a State process to develop a proposal to present to FERC for establishing a new independent ISO Board. The Legislature should expand the authority of the ISO from merely providing reliability to assuring economic efficiency and affordable costs for California. The Legislature should repeal current state law that prohibits the CPUC from eliminating the mandatory PX buy/sell requirement for UDCs

[7] The November 1, *2000 FERC Order Proposing Remedies for California Wholesale Electricity* concluded that prices for energy and ancillary services in the ISO market during the summer of 2000 were unjust and unreasonable.
[8] As noted before, the Energy Commission supports the need for fundamental redesign of the California market being pursued by the Governor, Legislature and FERC. However, the Energy Commission believes it is highly unlikely that such a monumental task can be accomplished before the summer of 2001.

2. **Allow Full Range of Contracting to UDCs**
   The Legislature should allow utility distribution companies (UDCs) to enter into forward contracts and hedging instruments. In addition, it should direct the CPUC to take steps that provide guidance to UDCs as to the kind of contracts and price levels that would not be second-guessed in ex post reasonableness reviews.

3. **Encourage Generators to Sign Reasonable Contracts or be Placed on Reliability Must-Run (RMR) Agreements**
   The California Legislature should encourage all generators, owned by merchants or surplus to the needs of publicly owned utilities, to sign bilateral and forward contracts with utility distribution companies for the majority of their output or be placed on RMR agreements to assure just and reasonable prices.

4. **Remove Influence of RECLAIM Costs On Electricity Prices**
   The Energy Commission requests that SCAQMD remove electric generators from the RECLAIM program and instead require the generators to contribute to a NO_x reduction fund.

5. **Authorize the Governor to Set Emission Control Retrofit Schedule**
   The Legislature should authorize the Governor to change the schedule for emission control installation if such change is in the best interests of California.

6. **Eliminate the Adverse Effects of Hold-back by Generators**
   The ISO should revise its market rules to allow generators to meet their own back-up requirements from reserves bid to the ISO. If the ISO fails to adopt such a rule change, the California Legislature should require in-state generators to account for how their capacity is bid and used.

Proposed Demand Mitigation Recommendations

7 **Increase Demand Responsiveness through Prices**
   The Energy Commission requests that the CPUC increase rates significantly during the summer season in order to send price signals to customers that induce increased energy efficiency.

8. **Increase Demand Responsiveness through Load Curtailment Programs**
   The Legislature should authorize the Energy Commission to coordinate commercial load curtailment programs.

9. **Institute a Play-it-Safe Educational and Demand-Reduction Campaign**
   The California Legislature should authorize the Energy Commission to coordinate an effort by all California utilities to conduct effective and targeted consumer education campaign to get the citizens of the state prepared for another summer

of tight supplies, especially if temperatures are high. The Energy Commission should establish a plan for emergency voluntary demand reductions as part of its contingency planning responsibilities that identifies in advance and then directs utilities to call customers to reduce demand when emergency conditions are declared.

Proposed Generator Mitigation Recommendations

10. Establish a Legitimate Purpose Rule for Generators

The Legislature should require generators to function under a legitimate purpose rule to help assure that the wholesale electricity market functions closer to the original intent of the Legislature.

11. Require Power Plant Owners to Take Steps to Minimize Outages

The Energy Commission should require generators to provide information and assessments of the risks of outages for the summer of 2001 and take appropriate measures to reduce outages. In addition, the Legislature should direct the ISO to develop an optimized outage schedule for the electricity system as a whole.

12. Recruit All Generating Capacity in California.

The California Legislature should direct the CPUC to offer a supplemental Standard Offer Contract that allows for recovery of costs for producing generation beyond those allowed in existing contracts. The Legislature should also order the CPUC to waive restriction for the year 2001 to allow QFs to increase the output of their generators.

BENEFITS

The Committee believes the above recommendations will significantly enhance reliability of the grid, mitigate electricity cost increases, and reduce air emissions for the summer of 2001. They will help to bring consumer rates more in line with actual wholesale electricity costs in the California market while at the same time shielding consumers from excessively high rates that have resulted from flaws in market design and rules. In addition, these mitigation recommendations will also assure that rates are more efficient, reflecting higher costs during peak than off-peak periods to encourage energy conservation and the implementation of energy efficiency measures.

The Committee s proposed mitigation will help to assure that all available generation in the state can be obtained by the ISO to maintain reliability at just and reasonable costs. They will also mitigate the exercise of market power by generators and market manipulations such as arbitrage from the market, thereby reducing wholesale electricity costs. In addition, they will help to mitigate the skyrocketing costs for emission credits.

The above potential recommendations will help to properly inform and prepare consumers for emergency events in the electricity market and allow them to meaningfully participate in solutions to high costs and reliability concerns through their own actions. Contingency planning and consumer education are vital components to this consumer readiness.

RECOMMENDATION 1
IMPLEMENT CHANGES IN ISO BOARD AND PX BUY/SELL REQUIREMENT

BACKGROUND

The decision released by FERC on December 15, 2000 includes at least two elements with which the Committee concurs.[9] These two elements call for changes in the ISO Board to make it an independent rather than stakeholder board and the elimination of the requirement that investor-owned utilities exclusively buy from and sell to the PX.[10]

Changes in ISO Board

Over the last few months there has been an increasing recognition of the potential for conflicts of interest on the part of stakeholder members of the ISO Board.[11] Many members of the current stakeholder board either sell power or own generating facilities. These board members can benefit from conditions that keep electricity prices high. The ISO Board s decision-making process has been criticized for being mired in controversy, overly complex and time-consuming, and prone to influence by special interest groups.

In response to concerns about the ISO Board, FERC has ordered that the current stakeholder ISO Board be replaced with an independent Board.[12] The current ISO Board is ordered to turn over control of the ISO to the ISO management. Under the FERC order the current ISO Board is allowed to remain in an advisory role only until a new Board is seated or April 27, 2001, whichever occurs first. FERC has stated it will issue an order to establish procedures to discuss with State representatives a process for selection of members of new independent ISO Board.

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[9] FERC Order Directing Remedies for California Wholesale Electric Market, Docket # EL01-10-000, December 15, 2000.

[10] The Committee believes the final decision s order to change the ISO Board to an independent board and to eliminate the PX are moves in the right direction. The Energy Commission is still in the process of comprehensively reviewing all elements of the FERC decision of December 15, 2000.

[11] The CPUC, EOB and FERC have all identified problems associated with conflicts of interest on the ISO Board and have recommended that an independent board be established.

[12] FERC Order Directing Remedies for California Wholesale Electric Market, Docket # EL01-10-000, December 15, 2000.

Problems with PX Buy/Sell Requirement

Current state law and CPUC regulations require that the investor-owned utilities in California to buy all the power they deliver to retail customers from the PX. In addition, they are required to sell power from nuclear and hydro generating facilities they own, as well as from QF and other contracts, into the PX. The PX then schedules these loads and resources, along with the schedules of other scheduling coordinators, into the ISO market.

Uniquely in California, the ISO and PX markets are artificially separated. California s existing market structure separates PX forward energy markets from the ISO s forward transmission allocation markets when over short horizons there is no distinction between energy dispatch and transmission access.[13] This separation does not allow the integration necessary to achieve both economic efficiency and reliable operations.[14] Furthermore, it creates opportunities for transactions through the PX and other scheduling coordinators that are otherwise unnecessary and produce arbitrage opportunities that are inefficient.

In addition, over-reliance on real-time markets has been identified as a major contributor to high prices during the summer of 2000.[15] This phenomenon has been described by some as a consequence of the market separation discussed above.[16] This summer chronic under scheduling of loads and generation resulted in a very high proportion of the total load needing to be served in real time with no prior warning. Under scheduling occurs:

§ When scheduling coordinators, including the UDCs, do not bid all of their load into the ISO and PX forward markets hoping that prices will fall in a subsequent market
§ When scheduling coordinators bid their loads in but reject available generator bids they consider to be excessively high
§ When scheduling coordinators bid in their entire load but there are insufficient generator bids to meet all of their loads as a result of unexpected outages or intentional withholding by generators.

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[13] *Electricity Market Reform in California*, John D. Chandley, Scott M. Harvey, and William W. Hogan, November 22, 2000

[14] The California Energy Commission, during the CPUC and FERC proceedings dealing with restructuring, advocated that greater efficiency would be achieved by having a system operator provide all dispatch, ancillary and transmission services.

[15] *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Anomalies*, FERC, November 1, 2000 and FERC Order Directing Remedies for California Wholesale Electric Markets, Docket # EL01-10-000, December 15, 2000.

[16] *Electricity Market Reform in California*, John D. Chandley, Scott M. Harvey, and William W. Hogan, November 22, 2000.

The requirement that investor-owned utilities sell into and buy out of the PX means that all of the customers of these utilities are exposed to the volatility that currently exists in the PX market. The separation of the ISO and PX market exposes electricity customers to further inefficiencies that raise prices.

The most recent FERC decision recognizes these problems and is eliminating the buy/sell requirement on investor-owned utilities. It proposed to release the 40,000˚MW of load for the investor owned utilities from the mandatory exposure to spot markets that results from the buy/sell requirements. FERC will now permit the investor-owned utilities to move their purchase power needs to long-term contracts that will mitigate cost exposure. The 25,000 MW of generation owned by or under contract to the investor-owned utilities may now be sold directly to retail customers subject to California regulation on a cost-of-service basis, subject to cost caps or any other way the State sees fit.

The FERC decision terminates the PX wholesale rate schedules as of April 30, 2000. FERC has determined that at a later time tariffs could be re-instituted, but that action depends on California s willingness to remove its mandatory buy sell requirement and development of prudent benchmarks for bilateral purchases. FERC notes while there is value in power exchanges, it cannot assure just and reasonable rates in the presence of mandatory exchange requirements such as the buy-sell requirement.

POTENTIAL RECOMMENDATION

Possible recommendations from the Committee to mitigate some of the more glaring problems with market design and rules would be:

The Governor and Legislature should immediately create a state process to develop a proposal for establishing a new independent ISO board for its discussions with FERC. This process should move expeditiously to assure that a new board can be in place prior to the April 27, 2001 FERC deadline. A State ISO Board Proposal developed under this process should use the requirements for independent governance of Regional Transmission Organizations as guidance.[17] The Committee recommends that the new ISO board should individuals and persons with expertise in the following areas: economics, state and federal power law and regulation, state and federal environmental regulation, and power generation and transmission. The Committee believes that the new ISO Board should also have an explicit duty to serve the public interest. ISO Board members must be able to demonstrate that they have no pecuniary interests in the outcomes of the decisions they make, other than as ratepayers.

The Legislature should repeal current state law that prohibits the CPUC from eliminating the mandatory buy/sell requirement before June 1, 2001.[18] The

[17] FERC Order 2000
[18] Adopted in the 2000-2001 Budget Act.

Legislature should further direct the CPUC to eliminate this buy/sell requirement from its decisions affecting the restructured market. The Legislature should also eliminate the PX and transfer any remaining markets that have value, such as some forward markets the ISO does not currently operate, over to the ISO. The ISO s authority should be expanded beyond merely providing for reliability of the statewide electricity grid, but also to achieve economic efficiency in its operations and affordable electricity costs for California. The Committee recommends that the ISO should have sole responsibility to operate the markets for day-ahead and real-time scheduling, balancing, congestion management, ancillary services reserves and all other electricity products and services that are parts of the integrated electricity system dispatch and provision of transmission access. This would eliminate the need for the Power Exchange, but might salvage some of its software development costs for which ratepayers have already paid.

BENEFITS

Changing the ISO Board from a stakeholder board to an independent body will ensure that necessary revisions to the market structure and rules to correct major flaws are made in the public interest. Eliminating the current separation between the ISO and PX functions will allow for more economic and reliable dispatch and operation of the generation and transmission system in the State. This will also eliminate many of the current problems with under scheduling, arbitrage between markets and products, and inefficient pricing signals. Elimination of these problems will help to bring electricity prices closer to marginal costs of electricity production that will, in turn, help to lower electricity prices and increase system reliability.

RECOMMENDATION 2
ALLOW FULL RANGE OF CONTRACTING FOR UDCs

BACKGROUND

Current state laws and policies limit the ability of UDCs to participate in forward contracting for their loads. UDCs can schedule some of their loads in the PX block forward market. However, these forward arrangements require physical energy delivery commitments. Other financial hedging instruments, such as contracts for differences or forward contracts weeks, months or even a year in advance, should be permissible for UDC.

Current rules do not allow UDCs to use the collective buying power of their customers to discipline generator bidding behavior. This limits the ability of load to be price responsive over longer time horizons than a day ahead-basis. The PX introduction of a block forward market for energy is a step in the right direction. But, loads still need more opportunities to be price-responsive, including allowing for a longer lead-time than the day before the delivery takes place.

In a market that allows many opportunities for forward financial contracting far in advance of delivery, loads would negotiate larger forward financial commitments with generation owners during hours when they expect their demand for electricity to be very high. This type of contracting would cause generators holding the supply side of forward contracts to find it in their financial interest to bid more aggressively in the day-ahead market, hour-ahead, and real time energy markets.

Just removing policies prohibiting UDCs from entering into forward contracts may not be enough to induce them to do so. Current policies protect them from being penalized for imprudent contracting if they restrict their buying to the day-ahead and real-time market. However, existing policies leave them open to second-guessing by regulators about the reasonableness of their long-term contracting practices.

Giving UDCs unlimited contracting authority without some reasonableness reviews could potentially expose ratepayers to imprudent contracting practices. On the other hand, it would not be appropriate to expose the UDCs to having their good faith judgements reviewed for prudency whenever it appears, in retrospect, that reliance on short-term markets would have achieved a lower price would prove unworkable. Instead, the State needs to develop mechanisms to give UDCs sufficient guidance to allow them to use forward contracts to limit generator market power.

FERC recommends a benchmark price for long-term contracts based on pre-restructuring retail rates. Others, such as the Market Surveillance Committee of the ISO have made other proposals for the construction of long-term contracts. These and other alternatives need to be fully explored. The Committee invites parties to bring recommendations for benchmark prices for long-term contracts to the January 4, 2001 workshop for further discussion.

POTENTIAL RECOMMENDATION

The Legislature should authorize the UDCs to have complete flexibility to hedge in forward markets. The UDCs should also have the ability to engage in tolling agreement .[19] To avoid a negative impact on price transparency in the electricity market, the prices, terms and conditions of all such contracts should be filed with the CPUC on a confidential basis. The CPUC should periodically make available to the public aggregated summaries of the kinds of contract terms being used and reports of the average prices reflected in the contracts. This should be accomplished without disclosing commercially sensitive information such as the specific terms of contracts or the parties involved.

In addition, The Governor and Legislature should direct the CPUC, in consultation with the Electricity Oversight Board and the Energy Commission, to develop a benchmark for long-term contracts, or baseline contract prices and conditions, in a public process to be completed no later than March 31, 2001. Contracts that meet these benchmarks or baselines would be deemed prudent and therefore not subject to review. Contracts that do not meet these requirements would be subject to reasonableness review.

BENEFITS

Eliminating restrictions on forward contracting by UDCs would provide significant long-term benefits to California consumers. Forward contracts and hedging instruments provide a highly effective buffer against price volatility in spot and/or real-time markets, because they provide buyers and sellers with a greater level of price certainty.[20] This occurs because UCDs can lock in fixed quantity of energy well in advance of the actual consumption of that energy. These contracts can also help to mitigate market power of generators who hold them.[21] For instance, contracts for differences require the generator to compensate the buyer for the difference between the energy spot price and the contacts actual prices when contract price is lower than the spot prices. On the other hand, it requires the buyer to compensate the generator when the contract price is higher. This reduces the generator s incentive to raise spot prices. These two impacts can potentially reduce the cost, incidence and magnitude of price spikes.

[19] A tolling agreement is when a power buyer purchases and delivers natural gas to a power plant owner who then converts it to electricity and sells that power back to the power buyer at a pre-specified efficiency or heat rate .
[20] Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Anomalies, FERC, November 1, 2000.

[21] Ibid.

Tolling agreements are a more direct way of forcing generators to reveal their underlying bidding-cost structure. PG&E, SCE and SDG&E are very familiar with operations of the existing power plants, since they were the previous owners. By delivering gas at a known price, the UDCs are quickly able to assess the power price being offered. The use of tolling agreements also will restrict the ability of market participants to manipulate the price of natural gas used to produce electricity

RECOMMENDATION 3 ENCOURAGE GENERATORS TO SIGN REASONABLE LONG-TERM CONTRACTS OR BE PLACED ON RMR AGREEMENTS

BACKGROUND

As previously discussed, FERC s decision releases the loads and resources of the investor owned utilities from the mandatory PX buy/sell requirement. FERC s decision identifies long-term contracts as central to mitigation of high prices in the electricity market. FERC notes that it cannot order California to establish long-term contracts for retail customers of investor-owned utilities to serve the remainder of the load that utility owned generation cannot meet. However, eliminating restriction on the UDCs, as suggested in Recommendation 2, will pave the way for the implementation of forward contracts in the State.

Most competitive electricity market within and outside the United State began restructuring with some form of vesting contracts in place to protect electricity customers from wholesale price volatility during the early years of the market.[22] These vesting contracts are usually purchased by load serving entities, such as utility distribution companies, to hedge against the financial risk associated with serving their customers on fixed retail rates during the initial period of competitive market operation.[23] Typically the amount of load that is covered by these vesting contracts declines over time as the spot market matures.[24]

The Committee believes it would be much more prudent to encourage generators, both merchant facilities and surplus generation owned by public utilities, to sign contracts with UDCs at just and reasonable prices than to rely on clearly flawed and inefficient market mechanisms that have been in place. Although it is too late to use traditional vesting contracts, the introduction of long-term contracts should help to stabilize the electricity market in California.

Merchant Generation

The lack of forward contracting in the current market creates opportunities and increases incentives for generation owners to exercise market power in spot energy

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[22] *Analysis of Order Proposoing Rememdies for California Wholesale Electric Markets (Issued November 1, 20000 ,* Market Surveillance Committee of the California Independent System Operator, December 1, 2000.

[23] Ibid.

[24] ibid.

and ancillary services markets. It also exposes UDCs to price volatility in these markets like what has been seen recently in California s electricity market. On the other hand, the price certainty provided by contracts provides generators a reliable source of revenue for the construction of new facilities.

One of the problems identified with using forward contracts under current circumstances is that generators might not be willing to forgo the current profits they enjoy from the extremely high electricity prices in the PX and ISO markets. In these circumstances generators would be expected to sign contracts that result in prices to UDCs that are not just and reasonable. However, a number of generators filed testimony with FERC indicating they would be willing to sign long-term contracts with utilities at rates ranging from $50.25 to $60.26 per MWh.[25]

The effect that long-term contracts have on spot prices may lead to reasonableness reviews. Forward contract commitments, either voluntarily made by generators or imposed on them by regulators, can significantly alter the incentives of generators to raise prices or withhold generating capacity.[26] With forward contracts in place, the incentive to bid more aggressively in the spot market tends to result in lower spot prices. The holder of these contracts could then be subject to reasonableness reviews, as noted in the discussion of the previous recommendation that would not be appropriate.[27]

Surplus Publicly Owned Utility Generation

Some publicly owned utilities have generation capacity that is surplus to their own requirements. This surplus generation made a significant contribution to supplies during the summer of 2000. The difficulty was that in some cases the ISO was forced to acquire these generating supplies at extremely high prices. Parties have alleged that some publicly owned utilities might have been withholding surplus capacity in order to drive electricity prices up.

In any case, there has been a wide divergence in how the publicly owned utilities have responded to the electricity crisis. During last summer s peak period, the Northern California Power Authority (NCPA), a collection of California publicly owned utilities, voluntarily signed RMR contracts with the ISO. While those prices more than covered costs, NCPA willingly gave up the potential for much more lucrative prices in order to help preserve California s electricity system reliability. LADWP, by comparison, offered its excess generation capacity after the ISO made out-of-market calls for power, selling its power into the system at prices considerably higher than most others.

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[25] Enron City of Roseville agreement and Duke proposal to SDG&E, respectively.

[26] *Analysis of Order Proposing Remedies for California Wholesale Electric Markets (Issued November 1, 20000 ,* Market Surveillance Committee of the California Independent System Operator, December 1, 2000.

[27] ibid.

Publicly owned utilities should not be able to take advantage of other utilities or their ratepayers simply because flaws in the market allow extremely high prices at times to meet reliability needs. Publicly owned utilities are an important part of the California market despite the fact that some decided not to become members of the ISO. As good neighbors, they should not be allowed to charge prices that are not just and reasonable and that are not in the public interest.

In recent years when devastating fires struck the Los Angeles area, firefighters from around the state responded. Not a single community sending fire fighters asked how much profit could be made off this crisis. Firefighters risked their lives for people they did not know and were unlikely to ever know because that is what good neighbors do. The people served by the investor owned utilities are facing a crisis. Good neighbors will help, not exploit and worsen the crisis.

RMR Contracts as a Fall-Back Measure

The ISO has the ability to require generators connected to the ISO to enter into RMR (Reliability Must Run) contracts. These contracts allow the ISO to direct the generators connected to the ISO grid to run at times when reliability of service is threatened by a shortage of capacity.

The ISO has chosen not to require all generators connected to the ISO grid to enter into RMR contracts for the summer of 2001. If generation is sold out of state, the reliability of electric service in California will be jeopardized. Since it is the more efficient and less polluting units that are most likely to be sold out of state, this will increase the use of higher polluting units in state and increase costs in California.

The ISO has the ability to prevent this increase in pollution in California. The ISO can require that all units connected to the ISO grid sign RMR contracts. The ISO has not exercised its rights, leaving the people of California exposed to the risk of less efficient, higher polluting units generating electricity in California.

POTENTIAL RECOMMENDATION

The Legislature should encourage merchant generators to sign long-term contracts with UDCs prices that meet benchmark prices described in Recommendation #2. These contracts should be put into place for the peak summer period, but no later than March 31, 2001. In the event these long-term contacts are not in place voluntarily by March 31, 2001, the Legislature should require the ISO to place all generators on RMR contracts to assure just and reasonable rates.

The California Legislature should order each publicly owned utility with surplus power to report to the Legislature by February 15, 2001, its intentions with regard to participation in the summer of 2001 wholesale electricity market. The Legislature should direct each publicly owned utility to work with the Energy Commission to produce a report to the Legislature by March 1, 2001. This report should detail the capability of the publicly owned utilities to mitigate the electrical crisis facing

California in 2001. The report should contain recommendations from the Energy Commission as to whether or not the Legislature should order one or more publicly owned utilities should sign RMR contracts with the ISO.

BENEFITS

The primary benefit of this recommendation is that it should provide sufficient incentive for generators, whether publicly owned utilities or merchant generators, to enter into long-term contracts. If this occurs, the cost of electricity can be expected to go down significantly from current levels. In addition, electric system reliability in California will be enhanced. This benefits all of the ratepayers of the State including those of the UDCs and municipal utilities.

RECOMMENDATION 4
REMOVE INFLUENCE OF RECLAIM COSTS ON ELECTRICITY PRICES

BACKGROUND

Each electric generator in the SCAQMD jurisdiction must purchase NO_x emission credits for each MWh that they generate. The generators add the cost of these credits to their fuel cost per MWh to determine their operating cost per MWh The operating cost sets the minimum bid for each generator since if they bid less, they lose money.

In the single price auction of the ISO and PX, the highest cost winning bid sets the price for all the winning bids. If all electric generators bid their operating costs and a generator paying for NO_x credits is the highest cost winning bid, then all winning bids are paid a price that includes the cost of the NO_x emission credits. This is true even if the bidder is a hydroelectric power plant operator in the Pacific Northwest, or a coal plant in the southwest or a gas fired power plant in Northern California.

In the high demand summer months, the generators buying NO_x emission credits had the highest operating costs in many hours and set the price for all power bought by the ISO and PX. It is estimated that the influence of the cost of NO_x emission credits on the single price auction added roughly $500 million to $2 billion to the cost of power in the summer of 2000.

The increase in wholesale power costs due to the inclusion of NO_x emission costs in the single price auction continues today. PG&E, SCE and SDG&E are incurring millions of dollars in wholesale power costs daily due to these NO_x emission costs from generators who do not pay these costs but who benefit from the workings of the single price auction.

The design of the single price auction is not the fault of the SCAQMD. In 1994, SCAQMD created a program titled RECLAIM to encourage large industrial stationary air emission sources, including electricity generators, to further reduce their emissions. The program established a market to allow emission permit holders to trade allowances in oxides of nitrogen (NO_x). The allowances are referred to as RECLAIM trading credits (RTCs).

Companies, including electric generators, participating in the program were initially allocated NO_x credits based on their highest annual emissions during a base period. To achieve desired reductions in emissions, the SCAQMD reduces the total number of NO_x credits each year. With fewer credits available, the electric generators must install control devices or reduce output as the credits are phased out.

Due to the record electricity consumption for electricity in 2000, the electric generators in the SCAQMD were called on to generate more than they did in the base period. Because of the phase out of credits, the generators did not have enough credits to generate even the base year amount. All the generators in the SCAQMD had to buy credits in unprecedented quantities, and the price of credits soared. The price of RTCs rose from less than $1 per pound in January 2000 to nearly $50 per pound by August 2000.

As a result of the breakdown in the market for RTCs, one electric generator shut down in mid December 2000. This nearly caused rotating blackouts in California. SCAQMD reached an agreement with the electric generator and the ISO to allow the generator to continue operating. The electric generator agreed to pay a fine and install NO_x controls.

SCAQMD has reached similar agreements with other electric generators in its jurisdiction. All of these electric generators will be installing NO_x control devices. When these devices are installed, there will be less need for RTCs and potentially less influence on the single price auction.

The reliance on the single price auction in setting wholesale power costs is also undergoing change. The FERC in its December 15, 2000 order encourages the California utilities to rely less on the single price auction and more on long-term contracts.

Both the installation of NOx control devices and the switch to long term contracts will take time. It is not in the public interest that electric generators are allowed to negotiate as if the opportunity cost to the California utilities is a power plant with $50˚per pound RTC costs.

The SCAQMD could act to help alleviate the damage to California caused by the excessive wholesale electricity costs. For example, SCAQMD could change the RTCs from an operating cost to a fixed cost, and cap the amount paid for RTCs by electric generators.

Instead of requiring the electric generators to buy RTCs for each MWh generated, SCAQMD could charge an annual fee to the electric generators. The fee could be used to fund NO_x reduction programs. The electric generators should treat such a fee just as if it were any fixed cost such as a mortgage or insurance payment. Neither of these fixed payments affects the operating costs nor the bids made by generators. A fixed fee emission program should also not affect operating costs or bids.

SCAQMD could cap the fee at $5.00 per pound of the technically feasible maximum emission level. This level was calculated for the CPUC in the EIR for the SCE fossil plant divestiture. It is the maximum potential generation less expected reductions such as forced and maintenance outages. This would be adjusted to reflect scheduled NO_x retrofits.

POTENTIAL RECOMMENDATION

Possible recommendations from the Committee would be:

The Energy Commission requests that the SCAQMD act immediately to separate the electric generators from the RECLAIM program and to substitute a fixed fee program.

If SCAQMD fails to act, the Legislature should order SCAQMD to revise the RECLAIM rules to remove all electric generators from the RECLAIM program, and to require each generator to pay an annual fee into a NO_x reduction fund. The annual payment shall equal five dollars for each pound of NO_x projected to be emitted at the facility at the technically feasible maximum operation. Under guidelines established by SCAQMD and at the discretion of SCAQMD, the fund may be operated by SCAQMD, a consortium of generators or by the individual generator.

BENEFITS

If SCAQMD removes the electric generators from the variable cost RECLAIM program, it will immediately begin to save millions of dollars per day in wholesale power costs. If SCAQMD requires the electric generators to pay an annual fee into a NO_x reduction fund, the goal of continual reductions in NO_x can be achieved. Changing the program can significantly reduce wholesale power costs while continuing to protect the environment.

RECOMMENDATION 5_______________ AUTHORIZE GOVERNOR TO SET EMISSION RETROFIT SCHEDULE

BACKGROUND

A large number of electric generating units will be retrofitted with NOx and other emission controls in 2001. Each unit must be taken out of service in order to install the emission control devices. The air boards, the generators and the ISO are working together to schedule the installation of the emission control devices so as to minimize disruptions to the electric system.

It is possible that even the best-designed schedule with the least expected impacts will still cause serious problems. An extended unexpected outage at one of the major plants such as one of the nuclear plants might occur. Rainfall in California, the Pacific Northwest or both may be well below average reducing hydroelectric output.

If an unexpected outage at a major power plant occurs, rescheduling of emission control installation to maintain higher operating reserves may reduce electric power costs by hundreds of millions of dollars. Recent events have shown that a shortage causes spikes in wholesale power costs. Postponing an emission control installation into the wrong time period may cause even greater costs to be incurred. A central authority with statewide and even regional perspective would be beneficial.

Recently hydroelectric power plant operators in the Pacific Northwest have generated electricity to serve California. Because of low rainfall to date, they expressed concern that releasing water now may harm the salmon runs in the spring. A series of major storms in January and February will alleviate this concern, but if they do not materialize, the Pacific Northwest will look to California to return the favor and generate power for them.

Since the spring is one of the periods of lowest demand in California, this is when emission control installation may be scheduled. It may also be when California will be called on to help the Pacific Northwest.

The ability to avoid price spikes or to help sustain the salmon population may be achieved while still working to reduce emissions. In the event of an emission control installation reschedule, the electric generator can contribute to an emission reduction fund.

POTENTIAL RECOMMENDATION

Possible recommendations form the Committee would be:

The Legislature should authorize the Governor to change the schedule for emission control installation if in his opinion such change is in the best interests of California and its relations with neighboring states. The Legislature should authorize the creation of a temporary task force composed of leading experts in the field. The task force should monitor the schedule for emission retrofit and apprise the Governor of any reasons to change the schedule.

The Legislature should require that in the event that the Governor reschedules the installation of emission controls that the affected electric generator pay into a emission reduction fund five dollars for each additional pound of emission estimated to be emitted as a result of the reschedule.

BENEFITS

Authorizing the Governor to reschedule emission control installation if events warrant while requiring contributions to an emission reduction fund will mitigate the adverse consequences of the untimely shutdown of power plants while still working to reduce emissions.

RECOMMENDATION 6
ELIMINATE ADVERSE EFFECTS OF HOLD-BACKS BY GENERATORS

BACKGROUND

Generators have reported that as part of their business practice that they may hold back as much as ten percent of their capacity as reserves against outages. They explain that they routinely enter into contracts with penalties for failure to deliver. To protect against paying these penalties, these generators hold back a portion of their capacity. This effectively creates a double reserve margin that gives the illusion that statewide reserve margins are lower than they are in reality.

Some generators only hold back capacity that they are using to self-provide their own ancillary service requirements. There is no harm in these circumstances because the ISO will realize that it need not provide additional reserves for the loads served by those generators. However there are circumstances where loads contract for a higher level of reliability and generators agree to pay heavy penalties for failure to provide that level of reliability. In this case, the generator may reasonably determine that it needs to hold back more capacity than it would hold back just to meet ISO-established ancillary service requirements. If the ISO is unaware of the details of these contractual obligations and the actions the generator is taking to meet them, the ISO may over-estimate the reserves that are actually necessary to maintain reasonable reliability of the entire system.

The practice of reserving capacity individually can damage the state as a whole when it causes the ISO to provide unnecessary amounts of system-wide reserves. Because withholding capacity is also a classic method of attempting to exercise market power, increasing the price of electricity, it is essential that the ISO have a clear understanding when there are legitimate contractual reasons for the creation of these private capacity reserves.

POTENTIAL RECOMMENDATION

A possible recommendation from the Committee would be:

The Legislature should direct the ISO to revise its market rules to require generators to provide detailed accounting of how their capacity is being used on an hour by hour basis. This will allow the ISO to know when they are holding capacity back for self-provision of reserves or for provision of additional levels of certainty to their ability to meet contract requirements.

BENEFITS

If the ISO changes its rules in this manner, it will allow the ISO to reduce public suspicion that capacity is being held back in an effort to exercise market power. It may also allow the ISO to reduce the total system reserves that it needs to acquire. In addition, this requirement would also allow the ISO, under some circumstances, to identify alternative ways of meeting the legitimate contractual needs of the generator at a lower system cost or with fewer adverse environmental impacts.

RECOMMENDATION 7 INCREASE DEMAND RESPONSIVENESS THROUGH PRICE CHANGES

BACKGROUND

The concept of demand responsiveness, or the ability of consumers to adjust their consumption based on efficient pricing signals, has been broadly accepted in recent months as an essential element of effective competitive markets. In this regard, AB 1890 created a disconnect between competitive wholesale markets and regulated retail markets that has been shown to have severe negative consequences.

The PX and ISO use conventional, albeit flawed, market mechanisms to determine a price that balances supply and demand. UDCs sell electricity to customers, essentially bundled service end-users, at rates that are frozen by AB 1890 at the rates in existence on June 10, 1996. Since UDC customers pay flat rates, they have no economic incentive to reduce loads when wholesale market prices are high, which are generally the same conditions that threaten reliability at system peak demand conditions. SDG&E customers were subject to market prices leading to extremely high bills during June but were subsequently placed under a price freeze by the Legislature.

Under tight supply conditions and without effective price-induced demand reductions, the circumstances existed during the summer of 2000, meeting peak demand required that literally every power plant, regardless of efficiency or its price bid, be accepted. Under PX and ISO market arrangements, the highest accepted price bid sets the price for all suppliers and all loads.

When supplies are scarce the supply side of the energy market is able to submit increasingly high generation bids that are unchecked by reductions in load bids. The result is price spikes whenever there is a tight supply versus demand condition; however, the majority of the price spikes occur in the summer months, although recent events show winter peaks with the same patterns.

Such prices provide the wrong signal to the supply side of the market, leading new generators to enter the market. They are wrong because end-user loads are being bid by agents into the market on the basis of the frozen rates that are utterly indifferent to wholesale market conditions reflecting the relative scarcity of electricity. The market is not really being cleared so that supply and ultimate end-user demand faces the same price at the margin. For SCE and PG&E, deferral of shareholder stranded cost recovery through the residual CTC is the actual market balancing mechanism.

A market structure that had an element of demand responsiveness would behave more predictably and produce more efficient price signals. Its prices would be lower than today s market produces because only end-users who actually valued electricity at high levels would be using it. Some end-users would not want to use electricity at such high rates reducing peak demand and reliability concerns at this same time. These end-users would behave this way because they have advance notice of market prices, metering and other mechanisms to measure or gauge their usage patterns, and effective means of controlling their usage to match their own perceived value of electricity.

For the summer of 2001, customer rates need to reflect higher summer season prices based on the realities of market conditions rather than the rates now employed. Achieving greater demand responsiveness will lower wholesale market-clearing prices. This is so because higher summer season rates will lead to price induced conservation. The resulting lower demand this summer will lead to lower wholesale costs. Recent research reveals that in high cost hours, just a three percent reduction in loads resulted in a twenty-five percent reduction in the wholesale market-clearing price.

SCE and PG&E still charge most of their customers at the frozen rates established in AB 1890. Those rates no longer cover the full costs of purchasing power from the wholesale market. The CPUC now has before it the issue of who is responsible for paying costs already incurred. SCE and PG&E have filed Rate Stabilization Plans with the CPUC to increase rates by 9.9 percent and 22.4 percent on average. The increased rates would be frozen for five years to recover past and expected wholesale power purchase costs. For most ratepayers, the power purchase portion of the bill would continue as it does today a flat year-round rate.

Unfortunately, a flat year-round rate fails to provide ratepayers with the price signals they need to know when power is most valuable, and when they should conserve. A primary mission of the Energy Commission is to promote conservation. The Committee believes that its sister agency, the CPUC, should order significant increases in summer seasonal rates. Through higher rates this summer, the CPUC will send the necessary information that electricity in the summer is valuable and scarce and ratepayers should conserve.

By making this recommendation, the Committee in no way takes a position on the merits of the applications for rate increases before the CPUC. Those decisions are properly the sole and exclusive jurisdiction of the CPUC.

The Committee realizes that a general rate case is complicated with many accounting and cost issues that take time to resolve. It is possible that the CPUC would not reach a decision before the time needed to begin the public education campaign to alert ratepayers to the increase in summer rates. The Committee proposes as a backstop that the Legislature adopt an automatic trigger if the CPUC is unable to act before a date certain. This applies only to the summer of 2001 and only due to the extraordinary circumstances facing California.

POTENTIAL RECOMMENDATION

Possible recommendations from the Committee would be:

The Committee requests that the CPUC order substantially higher summer season rates for the summer of 2001 for all customers of PG&E, SCE and SDG&E except CARE customers. The accounting treatment and whether to offset the higher summer season rates with lower fall rates would be at the sole discretion of the CPUC.

The Legislature should order that if the CPUC has not adopted such rates by March 31, 2001 that significantly higher summer season rates be imposed in order to achieve price-induced conservation. The extra revenues above those revenues from CPUC approved tariffs shall be placed in a balancing account or reserve fund. The CPUC in its sole discretion would determine the treatment of the funds in such balancing account or reserve fund.

BENEFITS

By increasing rates during the high-cost summer period, ratepayers will be better informed about the actual costs that their energy use imposes on the system. While these costs actually vary by the hour, at least these ratepayers will see the seasonal variation that is now muffled in rates.

Ultimately, if ratepayers respond to these rate increases with reduced demand, wholesale power prices also should fall. At peak load, small decreases in demand can lead to dramatic reductions in power prices.

An instructive example is the response by urban water consumers to the extended drought of the late 1980s and early 1990s. Through a combination of rate increases and consumer education programs, urban water use was reduced by as much as 25˚percent. If reductions of one-tenth of this amount could be achieved during summer peak loads, wholesale power prices could fall as much as 25 percent during those hours.

Price signals that better reflect higher costs in peak periods are also necessary to provide incentives to invest in the equipment and behavior that allow them to manage their electricity usage.

RECOMMENDATION 8
INCREASE DEMAND RESPONSIVENESS THROUGH LOAD CURTAILMENT PROGRAMS

BACKGROUND

The Energy Commission first voiced concerns about system adequacy in its July 1999 report that have since been widely embraced.[28] Interruptible programs are a critical element of California s response to supply adequacy problems. When generation supplies are not sufficient to meet demand, the ISO and UDCs must call on interruptible customers to reduce their loads to maintain grid reliability.

For the summer of 2000, UDCs proposed new load curtailment programs to augment their traditional interruptible rate programs. In addition, the ISO developed its own mechanisms to reduce loads at critical periods. In the absence of price response due to the rate freezes imposed by AB 1890 on most consumers in California, these programmatic efforts were crucial in getting by during the summer of 2000. Even during this summer 2000 period, plans were being developed to augment these programs for summer of 2001 in anticipation of continued stresses on system adequacy.

For summer 2001, the ISO has extended the exemptions that it has already authorized for loads to participate in its ancillary services markets. In addition, the ISO has formulated a revised Demand Relief Program that attempts to increase participation beyond the relatively meager level achieved in 2000.

The Legislature passed, and the Governor signed AB 970, which funded additional efforts that state government could undertake to augment what UDCs and the ISO had in motion. Both the Energy Commission and CPUC received these funds, which are mostly aimed at targeting additional energy efficiency measures for peak load reductions that can be achieved for this coming summer.

The UDCs, under the supervision of the CPUC in R.00-10-002, are investigating how interruptible rate programs and additional load curtailment programs can be devised and implemented for summer 2001. Interruptible rate contracts established years ago include opt-out provisions, which many participating consumers were planning to exercise due to the numerous interruptions they experienced starting during the summer of 2000 and continuing into the November-December 2000 period.

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[28] CEC, *High Temperatures & Electricity Demand: An Assessment of Supply Adequacy in California*, July 1999.

PG&E participants were allowed to opt-out in their normal November time period; and about 20 percent of participating load did so. SCE s opt-out period was deferred until later in the spring of 2001 pending review of that programs operation. It is unclear what capacity will be available for interruption during summer of 2001, but the recent Energy Commission projections of system adequacy rely upon as much interruptible load as was achieved last summer.[29]

A key component in managing and quantifying the savings from load curtailment programs is having timely data on electricity usage, for both the utilities and customers. Currently, the ISO does not collect such information directly from customers meters. The ISO balances the reported generation and transmission with metered loads at substations to maintain system voltage. For this reason, accounting for changes in individual customer loads on a real-time basis will require the installation of interval meters. Both PG&E and SCE currently have a stock of such meters not yet installed.

Coordination among the programs sponsored by various state agencies, UDCs, and the ISO is important because increasing the level of additional interruptible or curtailable capacity for summer 2001 is important measure for assuring the reliability of the electricity system. Shifting consumers from one program to another does not increase the aggregate capacity.

The entities designing these programs are aware of this concern, however, each is releasing the details of the programs it administers on an independent schedule. This can lead to inadvertent duplication of programs and/or participants or prevent California from taking advantage of the full synergies available among the programs.

For example, the Energy Commission has targeted about $10 million of its funds from AB 970 at programs that facilitate demand responsive curtailments by commercial building consumers. Financing made available by the Energy Commission would allow commercial building customers to purchase automatic response mechanisms to shift air conditioning temperature loads or lighting in response to high price signals. These customers would then participate in either UDC load curtailment programs or the ISO s Demand Relief Program. Thus, the details of the financial incentives that attract consumers to participate in these programs is a vital factor governing the actual response that the Energy Commission s funds help to facilitate.

[29] CEC Staff, *Summer of 2001 Forecasted Electricity Demand and Supplies*, November 2000.

POTENTIAL RECOMMENDATION

A potential recommendation from the Committee would be that the Energy Commission should undertake the following coordination actions:

- Commercial buildings should have the capability to receive a need to curtail signal from its local utility (or energy service provider) and alert the relevant personnel to take actions to reduce demand.[30]
- Commercial buildings should also have the ability to receive and display hourly day-ahead prices and warnings of emergency conditions so that the buildings can make arrangements ahead of time to implement load control strategies.
- Customers should be able to accept/reject curtailment requests and respond by either: 1) Manually dimming lights or adjusting thermostats or other equipment, or 2) Automatically modifying lighting or HVAC system operation with predefined control strategies triggered by the need to curtail signal, or 3) Using a combination of 1 & 2; for example the thermostat set points might rise automatically, but employees may be asked via email to manually turn off some lights, computer monitors, etc.
- Meters should transmit the building load (kilowatt-hour reading every 5 to 15˚minutes) to customers account at the utility (or energy service provider) so that load reductions relative to historic building loads (averaged over some predefined period) can be calculated. If the customer does not have an interval meter, AB 970 funds should be used to purchase and install one.
- Utilities (or energy service providers) should post the loads and estimated load reductions via the Internet so that the customer gets a real-time graphical feedback on actual load reductions achieved and the value of these load reductions.

BENEFITS

The actions listed above will help to ensure that the portion of CEC AB 970 funds set aside to facilitate demand responsiveness actions in commercial buildings are effective in contributing measurable load reductions for the summer of 2001. Continuing to pursue directly price responsive (or financial incentive responsive) programs is important to develop increased awareness among electricity consumers about fluctuating prices and the measures that can be taken by consumers to use load curtailment as an energy cost reduction technique.

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[30] This signal is a surrogate for the price signal referred to in AB 970. AB 970 envisages that the customer would respond to price (presumably market clearing prices), but, because of price caps, price is no longer well correlated with supply shortage, so temporarily we propose to create a surrogate need to curtail signal.

RECOMMENDATION 9
INSTITUTE A PLAY-IT-SAFE EDUCATIONAL AND VOLUNTARY DEMAND REDUCTION CAMPAIGN

BACKGROUND

The summer of 2000 caught nearly all consumers off guard. Electricity consumers do not receive their bills until four to six weeks after they have consumed their electricity. They currently do not have the information in advance of, or during, periods of peak loads in the state to be able to respond by shifting the energy use to off-peak periods or eliminating discretionary or unnecessary energy uses.

POTENTIAL RECOMMENDATION

A possible recommendation from the Committee would be:

The California Legislature should require all California utilities under the coordination of the Energy Commission to conduct an effective and targeted consumer education campaign to prepare citizens of the state for another summer of tight supplies, especially if temperatures are high or if hydro is low. The central message of the campaign should be: electricity supplies are tight and this summer the State s citizens need to help out by cutting back their consumption during peak times. The campaign should highlight the money savings that consumers can achieve by peak load-reduction programs. Information on peak-shaving measures must be made widely available to all consumers. The campaign should rely on news releases and features, electricity-bill inserts, mailings, and representatives sent to schools, city councils, consumer groups and all other reasonable venues to bring information to the State s electricity consumers about how they can help reduce their electricity bills.

BENEFITS

In the summer of 2001, an important element of the State s response to electricity shortages is to rely on consumers to help manage their energy use. This will reduce the costs for electricity for the entire State and help prevent blackouts.

RECOMMENDATION 10
ESTABLISH A LEGITIMATE PURPOSE RULE FOR GENERATORS

BACKGROUND

Generators, and the wholesalers that buy from generators and then resell electricity, have engaged in practices that appear to have no legitimate business purpose. These activities include artificially creating congestion, megawatt laundering and arbitrage. Other opportunities to manipulate market prices exist through gas prices and contracts particularly between vertically integrated affiliates.

There are also a number of major defects apparent in the ISO and PX market design and rules, adopted by their respective Boards, that resulted in extremely high wholesale electricity prices in 2000.[31] The following highlights a few of the more important flaws that have been identified.

The current market structure and rules create opportunities for the exercise of market power. Lack of demand responsiveness in the market permits generators, as a class, to exercise market power. They can raise prices knowing the ISO will pay almost anything in high load conditions to meet demand. As a result, when supplies are short, like during high temperature peaks, generators can submit extremely high bids without fear of having them rejected.

Another market design flaw that contributed to high prices in the summer and fall of 2000 was out of market (OOM) purchases made by the ISO at prices above the price caps for other ISO/PX markets. In addition it has increased the attractiveness of not participating in any of the advance (day-ahead or hour-ahead) energy and ancillary services market. Encouraging generators to withhold capacity serves to artificially drive up prices.[32]

The ISO makes out-of-market calls when insufficient generation is bid into the ISO market to meet demand. Generators are paid as bid capacity and energy charges —

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[31] Market rule and design problems have been identified in numerous recent reports by the ISO s Market Surveillance Committee, the CPUC/EOB Report of August 2, 2000, the FERC Staff Report and FERC Decision from November 1, 2000, and numerous other articles, papers and reports over the last several months.

[32] One means for in-state generators to withhold capacity in anticipation of an out-of-market (OOM) is to park their capacity at an out-of-state hub, such as Palo Verde, with a third-party scheduler. The third party scheduler then holds the in-state capacity out of the PX and ISO markets. The ISO then calls the third party scheduler for available capacity. The capacity is then delivered from the out of state hub, although it is really being produced by an in-state unit. If the power plant is on reliability must run agreement (RMRA) however; it cannot use this ploy.

as well as fuel-related start-up costs and gas imbalance charges — when they are called out-of-market. A generator can earn revenue from an out-of-market call that is significantly higher than that generator would have earned by participating in the PX energy and ISO energy and ancillary services markets.

A generator can artificially create congestion on the ISO grid when it bids a schedule that cannot be met due to transmission limitations. The ISO then paid the generator to change its scheduling in order to reduce congestion on the transmission line. But this would not have been necessary if the generator had not created the congestion in the first place. The ISO has paid at least tens of millions of dollars to generators who engage in congestion scheduling or what is known in the trade as the increment decrement game. The ISO then changes its tariff to reduce or eliminate payments to particular generators.

The ISO has not taken any actions to date that would eliminate payments to generators engaged in practices that have no legitimate business purpose. In the case of the increment-decrement game, it appears that the generator never intends to meet the schedule it submitted. In such instances, the only intention of the generator would be to extract millions of dollars from the ISO.

Another game played in the ISO market by generators and wholesalers is referred to in the trade as ping-pong or megawatt laundering . In this case, a generator or a wholesaler will schedule power out of state in a forward market. The generator or wholesaler will then try to obtain a price from the ISO that is greater than the cap price. There is no legitimate business purpose to the ping-pong or megawatt laundering game played by the generators and wholesalers. It appears that they have no intention of actually delivering power out of state when they play this game. The intent is to evade the price cap set by the ISO in the California market.

Generators and wholesalers can also maneuver to disturb the merit order of the power plant dispatch. In a merit order dispatch, the power plants are dispatched in order that reflects least cost. The most efficient are called on first, then the second most efficient and so on until the last unit called on is the least efficient increment needed to meet demand. The units that failed to be dispatched are held in reserve. Since the price in the ISO market is set using a single auction price, it is the last and least efficient unit used that sets the price for all units. This creates an incentive for generators and wholesalers to withhold an efficient unit in order to force a less efficient unit to set the auction price. Dispatching the less efficient units not only increases prices, but also increases air emissions since less efficient units burn more fuel and emit more pollutants.

Withholding units from the merit dispatch order reduces the reliability of the electrical grid. Units that should be held in reserve are forced into service, and reserves are reduced.

Another area of concern has been the spike in natural gas prices, particularly in Southern California.[33] California gas prices have diverged significantly upward from national natural gas prices. Electricity generators can hide their manipulation of electricity prices by paying apparently higher prices for natural gas. However, when the generator and gas supplier are affiliated, the entire electricity price is passed through to the parent company. One means of doing this is through a spark spread contract, where the gas price is calculated by dividing the electricity price by a pre-specified efficiency or heat rate. [34] These spark-spread prices then spread through the rest of the natural gas market as the opportunity costs of selling gas to other generators.

There is no legitimate business purpose to the games played by generators and wholesalers. Besides distorting the market and increasing the cost of electricity, these games increase air pollution and reduce electric system reliability.

POTENTIAL RECOMMENDATION

Possible recommendations would be:

The California Legislature should order the ISO to provide a complete accounting of the games played since the beginning of operations of the ISO to a state agency designated by the Legislature and an ongoing monthly and/or daily basis. This accounting should describe the game and estimate the change in air emissions, effect on electrical system reliability and increase in cost of each instance of game playing.

The Legislature should direct the Energy Commission to investigate if and how the natural gas market may be manipulated to increase electricity prices in California. The investigation should examine both physical gas supply constraints created by natural and artificial means, and contracting arrangements that lead to higher electricity prices.

The Legislature should institute fines for any entity that increases air emissions due to game playing equal to all revenues above cost for all electricity sold by that entity and all related entities on that day in the California market.

The Legislature should establish a whistle blower hotline for the reporting of game playing by generators and wholesalers in the California market.

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[33] Edison has filed a motion to suspend the current calculation of the short-run avoided costs (SRAC) paid to cogenerators. Edison claims that the market index price has been manipulated, thus making the current index inappropriate as a measure of the utility s avoided costs.

[34] This is the inverse of the tolling agreement described above.

BENEFITS

The primary benefit will be the reduction in unnecessary air pollution due to a reduction in the disturbance of the merit dispatch order due to game playing. The second benefit will be an enhancement to the reliability of the electrical system grid. A third benefit is to reassure the public that the Legislature is taking steps to eliminate game playing by wholesalers and generators in a market of critical importance to California. A fourth benefit is to aid in the containment of the cost of electricity.

RECOMMENDATION 11

REQUIRE POWER PLANT OWNERS TO TAKE STEPS TO MINIMIZE OUTAGES

BACKGROUND

During the summer of 2000, there was a significant increase in the rate of unplanned outages of power plants in California. These outages forced the ISO to call on less efficient plants to deliver electricity. This increased air emissions, reduced system reliability and increased costs.

Unplanned outages on the ISO system increased measurably in 2000. The data available shows that, for example, in August of 2000, there were 3,391 megawatts out of service on average during the month. This compares to an average of 604˚megawatts in August 1999. This is an increase of 2,787 megawatts, about 460˚percent. Recent experience is even more extreme, with total planned and unplanned outages in October and November of 2000 of approximately 11,000 MW, compared with about 2,000 MW for October and November 1999.

The loss of power plants due to unplanned outages reduced the ability of the ISO to serve load and to meet peak demand. The units that were unavailable had to be replaced by less efficient units. These units were no longer available for reserve duty. The result was reduced reliability, increased air emissions and higher costs.

Some parties attribute the increased rate of outages to the age of the plants in California and or the intense use of the plants in 2000. Others believe that power plants were declared out for unplanned maintenance in order to manipulate the market. Still others believe that merchant plant operators devote fewer resources to preventive and planned maintenance.

Studies of the available data indicate that there was a much lower rate of planned maintenance from April through August 2000 than occurred in the same period in 1999.

Age and intensity of use do not by themselves explain the exceptional increase in unplanned outages reported in 2001 by California generators. The United States Air Force uses a fleet of B52s that are older than the power plants in question. Despite occasional intense use these planes fly safely and reliably. The point is that there are steps that generator owners can take to improve the performance of their generating units.

Each generator owner can perform an outage risk analysis of its power plant. This analysis can identify the MTBF (mean time between failures) for each piece of equipment at the site. The owner can then make appropriate staffing and spares decisions to assure the least disruption in operations to the plant.

Transmission owners are already required to perform such analyses for the elements of their transmission systems and to provide that information to the ISO and its maintenance coordination committee. Similar information relating to generators would allow better coordination of maintenance outages. It would also allow for the development of guidelines or standards that would help minimize outages that impose unnecessary costs.

POTENTIAL RECOMMENDATION

Possible recommendations from the Committee would be:

The Energy Commission should revisit its data collection decisions relating to generators and should adopt regulations requiring the owners of electric generating units in California to perform an outage risk analysis for each such unit. The generators should be required to provide that information to the Energy Commission and ISO. The analysis should identify the staffing levels and spare parts the owner maintains in order to optimize uptime of the units. The Energy Commission should use its emergency regulation authority to require that the first such analysis is provided by March 1, 2001. In the event that generators object to providing this information, or fail to provide it, the Legislature should require it to be submitted to the Energy Commission and ISO and provide for civil penalties for failure to provide the information.

The Legislature should require the ISO to coordinate a system-wide optimized maintenance schedule to reduce the negative impacts of outages on electricity costs and reliability.

The Energy Commission should expand its energy shortage contingency planning efforts to collect data on outages of electrical units in California and report to the Legislature by March 1, 2001 on steps that the state might take to assist in reducing the frequency of unplanned outages of electrical generating units in California.

The Legislature should authorize the Energy Commission to employ individuals and firms knowledgeable in the industry to assist in these studies and to be available to assist in inspecting generating units to determine the actual cause of unplanned outages and to assist in planning to avoid future outages.

BENEFITS

Reducing unplanned outages will increase the use of the more efficient generating units. This will decrease air emissions, improve reliability and reduce costs. Outage risk analyses would help power plant operators to identify in advance those components of pieces of equipment that are likely to cause outages and help in doing preventive maintenance before the summer of 2001. Such analyses could also help to identify whether outages are the result of equipment and other failures rather than intentional withholding.

In addition, having spare components and parts on hand will significantly reduce the amount of time required to bring power plants back on-line in the state. These measures should contribute to decreasing the costs for providing reliability in the State. Identifying opportunities to increase the capacity available from existing generators through operational techniques could reduce the electricity costs for the summer of 2001 and improve the reliability of the electricity system.

RECOMMENDATION 12 RECRUIT ALL GENERATING CAPACITY IN THE MARKET

BACKGROUND

There are generators in California capable of increasing output at times of high demand. These generators either have no incentive to do so or are restricted by current industry practice.

Many if not all of these generators currently operate under PURPA related qualifying facility (QF) contracts, particularly the Standard Offer contracts offered in California. These units may be capable of increasing output through various means but are either not capable of recovering the full cost of their increased output or are restricted by regulations that define a qualifying facility.

For example, a unit may be capable of increasing output through the use of supplemental firing. However, its existing contract does not allow the generator to recover the higher cost of supplemental firing. It is possible that existing capacity sits idle due to contract constraints.

Other units may be capable of increasing output but are restricted by the definition of a qualifying facility. Small power producers have maximum output and natural gas usage restrictions. If they violate these restrictions they lose their QF status and jeopardize their standard offer contract.

Still others may be able to reduce steam deliveries or bypass the steam host altogether and thereby use the steam for electricity production. They are prevented from doing so by efficiency requirements that require the cogenerators to use a minimum amount of their energy as steam. The efficiency requirement may also inhibit the use of supplemental firing. Supplemental firing increases the heat rate of the facility and may cause an efficiency rule violation. It is possible that cogenerators may cause an efficiency rule violation. It is possible that cogeneration may be able to increase output if the efficiency standards were waived.

The independent power producers are proud of their contribution to the reliable delivery of electricity in California. After the Loma Prieta earthquake they advertised that the dispersed independently owned units were instrumental in supporting the grid and restoring it to full operations. If allowed to recover their costs and if protected from adverse regulatory consequences, it is likely that the independent producers will deliver additional power.

On December 8, 2000 FERC waived certain regulation for QFs that allows them to sell their excess production to load in California through negotiated contracts which paves the way for increasing the output of QFs in the state.[35]

POTENATION RECOMMENDATION

Possible recommendations from the Committee would be:

The Legislature should order the CPUC to direct the investor owned utilities to offer a supplemental Standard Offer contract to all existing independent power producers under contract. This supplemental contract shall allow the independent producer to recover the cost of production above the level called for in the existing contract.

The Legislature should also order the CPUC to waive for the year 2001 restrictions on increasing output for qualifying facilities consistent with the recent FERC decision. Such waiver shall allow the qualifying facility to increase output without loss of qualifying facility status.

BENEFITS

The increased capacity will contribute to improved system reliability.

[35] FERC December 8, 2000 in response to California ISO Filing 93FERC Section 61, 239.